Very High Penetration of Renewable Energy Sources to the European Electricity System in the context of model-based analysis of an energy roadmap towards a low carbon EU economy by 2050

Pantelis Capros, Nikolaos Tasios and Adamantios Marinakis

***Abstract*—This paper examines a series of scenarios achieving progressively very high levels of renewable energy sources (RES) share in the european electricity generation mix in the context of a roadmap to a low carbon economy in Europe quantified using the PRIMES model. Such high RES penetration levels practically require particularly high deployment of wind and solar, which are variable, else intermittent, sources of power. Implications that this inconvenient characteristic could have on the development of the european electricity system are investigated in this paper. Two moderating technologies are modeled, simulated and analyzed in terms of their ability to deal with the issue of intermittency: a) storage of energy in the form of hydrogen, and b) new DC transmission grid investments. A set of results are provided, illustrating the effect of each of these technologies.**

***Index Terms*—renewable energy sources, RES, intermittent, energy system modeling, EU electricity system**

I. INTRODUCTION

WIND and solar potential in the EU is big enough to cover almost the entire electricity consumption, with technology progress facilitating an increasingly higher penetration of those resources [1]–[4]. However, despite their huge potential, wind and solar power share an inconvenient characteristic. They are intermittent, or else variable, energy sources; that is, they cannot be dispatched (expect by curtailing output) and their output varies depending on local weather conditions [5]–[7].

In the context of a roadmap to a low carbon economy analysed for the European Commission using the model PRIMES [8], [9], this paper examines a series of scenarios achieving progressively very high levels of renewable energy sources (RES) share (reaching up to close to 100%) in the european electricity generation mix. Due to the limited potential and/or availability of other RES in Europe [10]–[13] such high RES shares are expected (and it turns out that they actually do so) to rely basically on variable sources. Purpose of this paper is to investigate and discuss implications that such a penetration would have on the development of the european electrical system.

The main constraints on incorporation of wind and solar generation at large scale stem from the need of perpetual balance between power production and gross power consumption in power system operation. For this to be satisfied, high intermittent RES penetration would require a significantly increased amount of system flexibility (ability of the system's power plants to quickly start up and/or rump up and down) compared to present day systems [5]. The limited cycling ability of large thermal generators makes "peak devices", such as gas turbines, a necessity for load-following and for use as operating reserves. This could result in huge, but occasionally used, investments, while their emitting of greenhouse gases (GHGs) could not comply with carbon intensity reduction targets [14]. In addition, considerable volatile electricity prices would be expected, due to the very different marginal electricity production costs of variable RES plants and conventional plants used for balancing [15]. Clearly, RES curtailment resulting from limited time coincidence of the variable resource with normal electricity demand is a waste of invested capital.

A variety of possible solution directions are on the table to facilitate the integration of variable RES in the electric power systems. A non-exhaustive list of the most discussed ones would contain: demand-side management, controllable loads, electricity storage, flexible thermal generation for load-following, optimal use and expansion of networks, stochastic tools for system operators, redesign of ancillary services and market clearing practices [16].

Large-scale energy storage and optimal transmission grid expansion have been selected from the above list to be modeled and thoroughly investigated in this paper. New transmission lines, properly located between countries, will facilitate common balancing in larger regions or even in an EU level, thus reducing the total reserve need, while at the same time this transmission grid expansion could allow taking benefit of possible geographical dispersion (and thus non-correlation of their availability) of variable RES units. Energy storage, on the other hand, can smooth generation of variable RES as in time-segments with excess of variable generation, electricity

---

Professor P. Capros is with E3MLab , Department of Electrical and Computer Engineering, National Technical University of Athens, Greece, GR, 15772 Greece e-mail: kapros@central.ntua.gr (see http://www.e3mlab.ntua.gr).

N. Tasios and A. Marinakis are researchers at E3MLab , Department of Electrical and Computer Engineering, National Technical University of Athens, Greece.

will be stored in order to be extracted in time-segments with low variable RES generation.

Variable renewable power integration has been the subject of numerous studies, focusing on different timeframes and levels of detail [17]–[20]. Interactions between wind farms and a storage moderating unit have been thoroughly investigated in the literature, with particular attention being paid to the combinations of wind power with hydro power plants [21], [22], with compressed air energy storage (CAES) [23], [24] and with hydrogen [25], [26]. Relative less studies exist that deal with an overall system optimization with energy storage as an option [23], [27]–[29]. Worth mentioning is the analysis in [5], which examines in general what changes to the grid would be necessary to accommodate extremely high penetration of variable renewables in terms of system flexibility and the potential role of enabling technologies such as energy storage.

What differentiates the models of the here-presented work from what exist in the literature is that long-term investment decisions are treated endogenously in the model together with short-term dispatching of units. Two moderating technologies (hydrogen storage and new, optimally located, DC lines) are modeled at the same time. Despite aggregated, enough detail has been introduced in the model to sufficiently represent shorter-term issues, as flexibility and reserve requirements, net load (demand minus available variable RES production) variations and power plant cycling constraints.

The remainder of this paper is organized as follows. In Section II, we present the mathematical model that has been used to represent a long-term optimization of the european electricity system, accounting for endogenous investment in new transmission lines as well as investment in energy storage. The results from the modeling of the various scenarios are presented and analyzed in Section III. The paper concludes with a discussion, based on the previously presented results, about the implications that high RES penetration may have to electricity systems.

II. MODELING SETUP

The PRIMES energy system model [30] has been used to simulate the various scenarios that are presented in this paper. In this section, a general overview of the PRIMES model is first given, followed by a more focused presentation of the power and steam generation sub-model of PRIMES. Then, the modeling in PRIMES of the two specific issues that are dealt with in this paper is presented in detail; large scale energy storage and transmission grid expansion.

A. The PRIMES energy system model

The PRIMES model is a simulation tool which combines economics and engineering for representing the energy decisions of agents, such as demanders and suppliers of energy forms, covering a medium to long-term horizon. It is a general-purpose model, conceived for energy outlooks, scenario construction and impact assessment of policies.

The model is organized in sub-models (modules), each one representing the behavior of a specific (or representative) agent. The representation is based on the microeconomic foundation of agents' decisions and simulates energy market equilibrium driven by prices. The model is very rich in representing current and future technologies in both demand and supply sectors and is dynamic with endogenous derivation of investment and tracking of technology vintages.

Its modular structure allows either for a unified model use or for partial use of modules to support specific energy studies. The model is made up of energy production sub-systems for supply (oil products, natural gas, coal, electricity and heat production, biomass supply, and others) and by end-use sectors for demand (residential, commercial, transport, nine industrial sectors). Some demanders may be also suppliers. The different modules interact via the exchange of fuel quantities and prices, leading to the overall dynamic equilibrium of the energy system.

B. The PRIMES power and steam generation sub-model

The sub-model that covers the purposes of this work is the so-called power and steam generation sub-model of PRIMES.

This PRIMES module simulates power generation and investment as a result of an optimization of the sector, assuming operational and grid constraints. The optimization is inter-temporal (perfect foresight) and solves simultaneously a unit commitment-dispatching problem, a capacity expansion problem and a DC-linearized optimum power flow problem (over interconnectors). The optimization is simultaneous for power, CHP, distributed steam, distributed heat, district heating and industrial boilers and satisfies synchronized chronological demand curves of power, steam and heat, which result from the sectoral demand sub-models.

Electricity trade among countries is endogenous but is constrained by interconnectors for which thermal capacity (today and in the future) and reactance are supposed known. The sub-model simulates a DC linearized power flow over a network with a single load node per country and multiple interconnectors among the nodes.

Electricity and steam/heat load are represented as chronological load curves with several typical time zones annually (referred to as load segments hereafter). Each such segment covers a portion (in hours) of the entire year, depending on which time zone it is aggregating.

It is assumed that the Internal Electricity Market in Europe gradually moves towards a well-functioning market and thus the least cost approach that the sub-model takes for unit commitment and capacity expansion in power generation is appropriate, being consistent with a competitive market.

Power technologies are characterized by the type of fuel they can use, their efficiency in generating power and/or heat, their cogeneration technique (if applicable), their availability, their investment costs and their operating costs.

The stochastic or variable RES are represented as a deterministic equivalent power capacity: nominal capacity is reduced according to the resource availability rate. This is done through a "utilization rate" index, multiplying RES installed capacity, taking values much lower than 1. It varies by country and yearly load segment depending on assumptions about dispersion of RES sites.

Equations (1a)-(1g) aim at presenting the above-described optimization problem in a nutshell, focusing on its essence and avoiding entering into details that are not necessary for the understanding of the remainder of this paper.

$$\min_{\mathbf{G},\mathbf{G}^{cp},\mathbf{P},\mathbf{F}} z\left(G_{(i,n,s,t)}, G^{cp}_{(i,n,t)}, F_{(i,n,f,s,t)}\right) \tag{1a}$$

subject to

$$\sum_{n}\sum_{f} G_{(i,n,f,s,t)} = C_{(i,s,t)} + \sum_{b}\left\{M_{(i,b)}P_{(b,s,t)}\right\} \qquad \forall i,s,t \tag{1b}$$

$$P_{(b,s,t)} = \sum_{i}\left\{Y_{(b,i)}\left[\sum_{n}\sum_{f} G_{(i,n,f,s,t)} - D_{(i,s,t)}\right]\right\} \qquad \forall b,s,t \tag{1c}$$

$$F_{(i,n,f,s,t)} = hr_{(i,n,t)}G_{(i,n,f,s,t)} \qquad \forall i,n,f,s,t \tag{1d}$$

$$0 \leq G_{(i,n,f,s,t)} \leq ur_{(i,n,s,t)}G^{cp}_{(i,n,t)} \qquad \forall i,n,f,s,t \tag{1e}$$

$$P^{min}_{(b,s,t)} \leq P_{(b,s,t)} \leq P^{max}_{(b,s,t)} \qquad \forall b,s,t \tag{1f}$$

$$\sum_{s}\left\{hs_{(s)}F_{(i,n,f,s,t)}\right\} \leq F^{max}_{(i,n,f,s,t)} \qquad \forall i,n,f,t \tag{1g}$$

Indices i, n, f, s, t and b refer, respectively, to countries, types of power plants, fuels, load segments, years and interconnectors. Problem's (1) variables are the electricity productions $\mathbf{G}$, the power plant capacities $\mathbf{G}^{cp}$, the inter-country power flows $\mathbf{P}$ and the fuel consumptions $\mathbf{F}$. For example, $G_{(i,n,f,s,t)}$ is the amount of power produced at the sth load segment of the tth year from power plants of type n in the ith country by consuming the fth type of fuel.

Objective function is the overall cost minimization; O&M costs of power plants, investment costs of new production capacity, fuel costs. Equation (1b) ensures that at every load segment total generation in each country equals total demand plus net imports. $\mathbf{C}$ contains the electricity consumption and is derived from the demand module of the PRIMES. Parameter M is a matrix of 0, 1, and -1 denoting the topology of the network. Let us note that in the actual implementation, losses are also accounted for, but this is not shown in (1) for the sake of presentation simplicity. The interconnector power flows are computed in Eq. (1c). $\mathbf{Y}$ is a PTDF matrix, connecting net country power excess/deficit with inter-country power flows. Parameter $hr_{(i,n,t)}$ in Eq. (1d) is the nth power plant's heat rate value, defining the amount of fuel that needs to be consumed for a unit production of electricity. Equations (1e) and (1f) make sure, respectively, that power plant production does not exceed its installed capacity in each country and that power flows are kept within the interconnectors' limits. Parameter $ur_{(i,n,s,t)}$ is the utilization rate referred to previously. For conventional plants it is very close to 1 (accounting for maintenance works and unexpected events), while for intermittent RES plants its values vary over the load segment, years and countries. Finally, Eq. (1g) limits the consumed fuel to what is available. Parameter $hs_{(s)}$ is the amount of hours that are assumed belonging in the sth load segment, while F^{max} is the available fuel quantity, measured in energy units and stemming from other PRIMES modules.

The actual optimization problem solved in the PRIMES power and steam generation sub-model is much richer and more involved than the above presented one. Let us shortly bring up the most important features not presented in (1). Apart from electricity, production and consumption of steam and heat is also modeled, as well as cogeneration of heat and power. The blending of fuels is considered. Constraints modeling reliability issues, security of supply prerequisites and limited cycling abilities of large power plants are also part of the model. Additional constraints, similar to (1c) and (1f), are also there to represent net transfer capacities (NTC) between countries as set by their system operators for security or reliability reasons. Power plants' lifetime is explicitly considered, with possibility of building new capacity, retrofitting old one or even replacing it. CO2 emissions add to the total cost through a carbon price. A CCS (carbon capture and storage) possibility can be added to existing plants, while new plants can be constructed with this additional auxiliary service.Finally, fuel prices and unit investment costs depend on volumes demanded and invested so as to reflect assending cost supply curves of resources.

C. Hydrogen Energy Storage

The sub-model formulates endogenously the accounting for investment in (and operation of) technologies that enable the storage of energy in the form of hydrogen and the subsequent use of the latter to produce electric energy when needed [26].

Presently, the relative disadvantage of this technology is its cost, which is expected, however, to decrease as the technology becomes more mature and widely used. On the other hand, hydrogen has some additional properties (apart from just being used as an intermediate storage mean); it is a reducing agent, used chemically in applications like the reduction of iron and ammonia synthesis, while it is a portable fuel which can be used wherever a fuel is now used. This makes hydrogen an interesting plausible energy carrier that would be used complementarily with electricity [31], [32]. Although not considered in this work, let us quote that the modeling of energy storage presented in the sequel could accommodate other storage technologies as well, like batteries and CAES [5], [28], [29], [33]. Let us also quote that endogenous hydro pumping is already contained in the PRIMES model.

Energy storage through hydrogen is achieved in three steps: a) consumption of electric energy to produce hydrogen from electrolysis, b) storage of the produced hydrogen, and c) consumption (part) of the stored hydrogen to produce electric energy in distributed plants or blended with natural gas in gas turbines and GTCCs.

Endogenously in the model, it is decided if, when and at what degree it is worth making investments that permit hydrogen storage, thus "decoupling" RES electricity production from electricity demand. Investment in hydrogen storage implies direct costs (investment and operating costs of the related technologies), but also indirect costs. The latter stem from the inefficiencies (hence, power losses) in the cycle electricity - hydrogen - electricity. On the other hand, no fuel cost needs to be paid (since power is initially produced from RES), while reserve requirements are decreased.

The following extension of the aggregated model description (1) illustrates the above described new features:

$$\min_{\mathbf{G},\mathbf{G}^{cp},\mathbf{P},\mathbf{F},\mathbf{H},\mathbf{H}^{cp},\mathbf{E}^{cp}} z\left(G_{(i,n,s,t)}, G^{cp}_{(i,n,t)}, F_{(i,n,f,s,t)}, H_{(i,t)}, H^{cp}_{(i,t)}, E^{cp}_{(i,t)}\right) \tag{2a}$$

subject to

$$\sum_n \sum_f G_{(i,n,f,s,t)} = C_{(i,s,t)} + \sum_b \left\{M_{(i,b)} P_{(b,s,t)}\right\} + H_{(i,s,t)} \quad \forall i,s,t \tag{2b}$$

$$P_{(b,s,t)} = \sum_i \left\{ Y_{(b,i)} \left[\sum_n \sum_f G_{(i,n,f,s,t)} - D_{(i,s,t)} - H_{(i,s,t)} \right] \right\} \quad \forall b,s,t \tag{2c}$$

$$F_{(i,n,f,s,t)} = hr_{(i,n,t)} G_{(i,n,f,s,t)} \quad \forall i,n,f,s,t \tag{2d}$$

$$0 \le G_{(i,n,f,s,t)} \le ur_{(i,n,s,t)} G^{cp}_{(i,n,t)} \quad \forall i,n,f,s,t \tag{2e}$$

$$P^{min}_{(b,s,t)} \le P_{(b,s,t)} \le P^{max}_{(b,s,t)} \quad \forall b,s,t \tag{2f}$$

$$\sum_s \left\{hs_{(s)} F_{(i,n,f,s,t)}\right\} \le F^{max}_{(i,n,f,s,t)} \quad \forall i,n,f,t \tag{2g}$$

$$0 \le H_{(i,s,t)} \le E^{cp}_{(i,t)} \quad \forall i,s,t \tag{2h}$$

$$0 \le \sum_s \left\{hs_{(s)} rt_{(i,t)} H_{(i,s,t)}\right\} \le H^{cp}_{(i,t)} \quad \forall i,t \tag{2i}$$

$$\sum_s \left\{ hs_{(s)} \sum_n F_{(i,n,\text{“}h\text{”},s,t)} \right\} = \sum_s \left\{hs_{(s)} rt_{(i,t)} H_{(i,s,t)}\right\} \quad \forall i,t \tag{2j}$$

Where the new variables $\mathbf{H}$ $\mathbf{H}^{cp}$ and $\mathbf{E}^{cp}$ denote, respectively, the amount of power that is consumed for electrolysis, the amount of hydrogen storage capacity (measured in MWh) and the electrolyzer's capability. Equations (1b) and (1c) have been replaced by (2b) and (2c), to comprise $\mathbf{H}$. Three new constraints have been added, namely Eq. (2h), Eq. (2i) and (2j). The first limits the power consumed for electrolysis to not exceed the installed electrolyzing capability. The second makes sure that no more hydrogen is stored than the installed storage capacity. Parameter $rt_{(i,t)}$ is the efficiency ratio at which power is converted to hydrogen. The equality in Eq. (2j) constraints the total hydrogen that has been produced in a country during a certain year to be entirely consumed in the same country during the same year (no inter-country hydrogen transportation network has been modeled).

D. *Endogenous investment in new DC interconnectors*

For the purposes of this work, the power and steam generation sub-model has been modified to account for endogenous transmission grid expansion. This takes on the form of making the construction of new DC lines, interconnecting countries, to be a variable in the optimization. Such new lines permit to enhance inter-country transmission capacity up to the level that is economically profitable.

The choice of DC stems from anticipating a possible evolution of the European grid, where a DC backbone could act as a highway network that would bring renewable energy (produced in remote sites such as in North Sea and in North Africa) to the big load centers of the continent. Advantages of such a DC grid, compared to the AC alternative, are the lower cost of DC transmission at very high distances, together with the higher controllability that such a grid offers. The value of the latter may be of special interest in a very high RES penetration scenario, where power flows in the transmission grid would be expected to vary significantly, even during the same day, following the weather conditions, instead of fitting in a rather predictable pattern as has been typically the case in power system networks.

Thus, the inter-country DC transmission capacity is now a variable. Power flows in DC lines are treated differently than those in AC lines. The latter are linked with the countries' net power surplus or deficit by the power transfer distribution factors (PTDFs). On the other hand, flows in DC lines are set by the solver when performing the optimization without any link between each other (apart from being such that each country's balance is maintained). This reflects the fact that the flow in a DC-link can be controlled by the link's operator.

Each country's net power surplus (positive) or deficit (negative) minus the country's exports flowing in DC lines plus the imports in DC lines give the net power that is to flow divided in the country's AC interconnectors according to the PTDF values.

Problem (1) takes on the following form:

$$\min_{\mathbf{G},\mathbf{G}^{cp},\mathbf{P},\mathbf{F},\mathbf{D},\mathbf{D}^{cp},\mathbf{E}} z\left(G_{(i,n,s,t)}, G^{cp}_{(i,n,t)}, F_{(i,n,f,s,t)}, D^{cp}_{(k,s,t)}\right) \tag{3a}$$

subject to

$$\sum_n \sum_f G_{(i,n,f,s,t)} = C_{(i,s,t)} + \sum_b \left\{M_{(i,b)} P_{(b,s,t)}\right\} \quad \forall i,s,t \tag{3b}$$

$$P_{(b,s,t)} = \sum_i \left\{ Y_{(b,i)} \left[\sum_n \sum_f G_{(i,n,f,s,t)} - D_{(i,s,t)} + E_{(i,s,t)} \right] \right\} \quad \forall b,s,t \tag{3c}$$

$$F_{(i,n,f,s,t)} = hr_{(i,n,t)} G_{(i,n,f,s,t)} \quad \forall i,n,f,s,t \tag{3d}$$

$$0 \le G_{(i,n,f,s,t)} \le ur_{(i,n,s,t)} G^{cp}_{(i,n,t)} \quad \forall i,n,f,s,t \tag{3e}$$

$$P^{min}_{(b,s,t)} \le P_{(b,s,t)} \le P^{max}_{(b,s,t)} \quad \forall b,s,t \tag{3f}$$

$$\sum_s \left\{hs_{(s)} F_{(i,n,f,s,t)}\right\} \le F^{max}_{(i,n,f,s,t)} \quad \forall i,n,f,t \tag{3g}$$

$$E_{(i,s,t)} = \sum_k \left\{N_{(i,k)} D_{(k,s,t)}\right\} \quad \forall i,s,t \tag{3h}$$

$$-D^{cp}_{(k,s,t)} \le D_{(k,s,t)} \le D^{cp}_{(k,s,t)} \quad \forall k,s,t \tag{3i}$$

Where the new index k refers to the DC lines, whose construction and flow control are decision variables of the model. Three new variables have been added; $\mathbf{D}^{cp}$ contains the endogenously constructed new DC lines' capacities, $\mathbf{D}$ the power flowing in those lines and $\mathbf{E}$ is the countries net export or import through those DC lines. The latter is taken into account in Eq. (3c). The meaning of Eq. (3h) and (3i), which

		Available Options			
		None	Only H	Only DC	Both
	60%	60	60-H	60-DC	60-full
RES	70%	70	70-H	70-DC	70-full
penetration	80%	80	80-H	80-DC	80-full
	90%	90	90-H	90-DC	90-full

TABLE I
SCENARIO CLASSIFICATION.

t	2010	2015	2020	2015	2030	2035	2040	2045	2050
e.r.	11%	16%	32%	49%	61%	72%	84%	94%	97%

TABLE II
INCREASING CO2 EMISSION REDUCTION (E.R.) TARGET FOR POWER GENERATION.

have been added to the model, is straightforward. Parameter N is a matrix of 0, 1, and -1 denoting the topology of the DC lines.

III. SIMULATIONS - RESULTS

A. Scenario setup

Data comprising the European Union's 27 member states have been fed into PRIMES to simulate various scenarios. These can be grouped into four families. One where neither hydrogen storage technologies nor endogenous DC transmission investment are available options in the model, one where only hydrogen storage and another where only DC transmission investment are available and, finally, one family of scenarios where both new options are available when solving the PRIMES model. The various scenarios are also differentiated in terms of RES penetration targets, while they all take into account the decarbonization target of 80% reduction in greenhouse gas emissions emitted by all activities in all sectors in year 2050 compared to year 1990 in Europe [8]. This target is translated to a 96% reduction in CO2 emissions in the electricity sector. Table I names the various scenarios that have been run.

Depending of the scenario, the proper extension of the PRIMES model has been used, as presented in Section II. For the scenarios where both hydrogen storage and DC transmission investment are available, the problem that has been solved is a merge of Prbls. (2) and (3). The simulation horizon covers the period from year 2010 to 2050.

In all scenarios, the target of -96% in CO2 emissions has been progressively imposed, increasing on a yearly basis, throughout the simulation years, so as to smoothly drive the power generation investments towards the final goal in 2050. Table II shows the emission reduction targets that have been used in all scenarios.

On the other hand, the RES deployment target has been imposed in the model as a constraint on year's 2050 power production as follows

$$\sum_{i}\sum_{n\in RES}\sum_{f}\sum_{s} G_{(i,n,f,s,\text{“2050”})} \geq \\ tg \textstyle\sum_i \sum_n \sum_f \sum_s G_{(i,n,f,s,\text{“2050”})}, \qquad (4)$$

		Available Options			
		None	Only H	Only DC	Both
	60%	101.4	101.2	100.0	100.0
RES	70%	108.2	105.6	103.6	103.5
penetration	80%	122.3	111.6	110.4	108.9
	90%	137.3	120.1	126.2	116.9

TABLE III
RELATIVE TOTAL COSTS FOR PERIOD FROM 2030 TO 2050 (EXPRESSED AS PERCENTAGES OVER THE COST OF SCENARIO “60-FULL”).

where tg is the sought percentage of RES production over total power production. It is up to the optimization performed by the model to manage the investments in the entire simulation period such that the target is reached in the most economical way. Expectedly, even if not explicitly asked for, an increased RES penetration in years prior to 2050 is driven by the need of reaching the CO2 reduction targets for these years. Solutions for CO2 reduction that do not go, at least partially, towards the sought RES penetration direction (like making big investments in nuclear) are disadvantageous due to the waste of investments that this would finally mean, given the RES deployment target that should be finally satisfied.

B. Results assessment

A set of problem variables together with some composed indices have been used to illustrate the effect of hydrogen storage deployment and of new transmission investments in accommodating high RES production.

Table III provides a comparison of the various scenarios in terms of relative costs. As the RES deployment increases with an increasing rate while approaching year 2050, it is after 2030 that RES penetration becomes significant. For this reason, the costs presented in that table comprise the years from 2030 to 2050, with each scenario's total cost being the sum of the corresponding yearly costs. Scenario “60-full” has been used as the scenario of reference, being the one with the least total cost.

Focusing, first, on each line of Table III, one can see that the presence of one or both moderators allows the penetration target to be achieved with a lower cost. Interestingly, for RES penetration up to 80%, it is the enhancement of the transmission system that is more beneficial, while when RES penetration reaches a 90% level, energy storage takes on the lead as the most beneficial enabling technology. Looking now at Table's III columns, the reader can see that, in all cases, increasing RES penetration is achieved with an increased total cost (this suggests that policies are required to achieve high RES penetration). However, the higher the RES penetration level, the more beneficial is the presence of each and both the moderators. For instance, the relative increase in total cost from scenario “60” to “90” is considerably higher than the relative increase from scenario “60-full” to “90-full”. Looking at Table III in the horizontal direction provides further insight to this observation; the higher the RES penetration, the higher the cost difference between scenarios with resort to one or both moderators and those without.

It is also of interest to check out at what degree have the additional options been used in the relevant scenarios, i.e.

		Available Options	
		Only H	Both
RES penetration	60%	0.4%	0.1%
	70%	2.0%	1.0%
	80%	4.1%	2.8%
	90%	6.1%	5.2%

TABLE IV
PERCENTAGE OF ENERGY PRODUCED FROM HYDROGEN OVER TOTAL ENERGY PRODUCTION IN 2050.

		Available Options	
		Only DC	Both
RES penetration	60%	15%	14%
	70%	22%	18%
	80%	28%	19%
	90%	30%	19%

TABLE V
PERCENTAGE OF SUM OF NEW DC INTERCONNECTORS' CAPACITIES OVER TOTAL INTERCONNECTING CAPACITY IN 2050.

		Available Options	
		Only H	Both
RES penetration	60%	1.0%	0.1%
	70%	3.9%	1.9%
	80%	6.7%	4.6%
	90%	8.8%	7.4%

TABLE VI
PERCENTAGE OF RES PRODUCTION CONSUMED FOR HYDROGEN ELECTROLYSIS IN 2050.

		Available Options			
		None	Only H	Only DC	Both
RES penetration	60%	1.8%	1.7%	1.7%	1.6%
	70%	5.1%	1.9%	3.4%	1.7%
	80%	7.4%	2.9%	5.0%	2.4%
	90%	33.8%	4.1%	12.0%	2.9%

TABLE VII
FRACTION OF RES THAT HAS BEEN CURTAILED IN 2050 OVER THE TOTAL ENERGY THAT COULD HAVE BEEN PRODUCED IF THERE HAD BEEN NO CURTAILMENT AT ALL.

		Available Options			
		None	Only H	Only DC	Both
RES penetration	60%	22.4	21.6	21.5	21.1
	70%	24.6	22.3	23.3	21.5
	80%	28.8	23.6	26.9	22.2
	90%	31.1	24.6	30.1	22.0

TABLE VIII
BACK-UP CAPACITY AS A PERCENTAGE OVER PEAK DEMAND IN 2050.

hydrogen storage technologies in all "H" and "full" families of scenarios and new DC transmission lines in all "DC" and "full" families of scenarios. The percentage of gross electricity generation from hydrogen over total gross generation in year 2050 has been used as an index to measure the penetration of hydrogen storage. To a similar purpose, the percentage of the sum of all new DC interconnectors' capacities over the total interconnecting capacity across Europe in year 2050 has been used as a measure of resort to new DC transmission. Tables IV and V show respectively the values of those indices. The reader can notice that the higher the RES penetration the more each moderator is used. In addition, comparing the two indices' values in the "full" family of scenarios with their respective values in "H" and "DC" families, one can see that there is a degree of exchangeability between the two moderators.

As additional relative information to Table IV, the percentage of RES gross production that is consumed for hydrogen electrolysis in 2050 is contained in Table VI.

Table VII shows the fraction of variable RES generation that has been curtailed in 2050. It corresponds to generation that was available but could not be absorbed given the total electricity demand and the transmission system capabilities. Without a moderating technology, one can see that the amount of curtailment raises up very significantly as the RES penetration level increases. Clearly, energy storage has a beneficial effect. Noteworthy is the fact that even without storage investments, proper grid reinforcement by itself allows to decrease the fraction of RES curtailment. This is thanks to the possibility of better exploiting the geographic dispersion of various RES, available at different time segments.

The capacity factor of a power plant in one year is defined as the total energy production of this plant during the year under question over the product of the power plant's capacity times the total number of hours of one year. The denominator of the above fraction tells how much energy would the plant have produced if it had been operated seamlessly during the entire year at its maximum capacity. Similarly, one can define the aggregated capacity factor of a set of plants as their total production in one year over their total capacities times the total number of hours of one year.

The higher the penetration of variable RES the lower their capacity factor is expected to be due to the curtailment issue previously presented and, also, due to the fact that as more variable RES are installed the last ones are expected to be constructed in less efficient locations, as the best locations will be already occupied. For instance, for the "90%" family of scenarios, we have computed the aggregated capacity factor of all variable RES plants that have been added to the generation mix in year 2050. The result has been the following factors: 0.09 for scenario "90", 0.17 for "90-DC", 0.20 for "90-H" and 0.21 for "90-full". Note that the aggregated capacity factors for all variable RES plants that have been in operation in 2050 are, respectively, 0.19, 0.23, 0.24 and 0.24. Worth noting are, first, the negative effect that the absence of a moderator has and, second, the comparatively more beneficial role of hydrogen storage than transmission enhancement.

As the level of RES penetration increases, more generation capacity needs to be installed but scarcely used. This generation capacity covers reserve requirements set by the system operators, but also it needs to be there in order to cover periods when demand peaks while RES availability is reduced. Table VIII shows, for each scenario, the percentage of generation capacity that has been in operation (i.e. producing energy) for at most 200 hours in year 2050 over the peak demand of the same year. The reader can notice the significant increase of this back-up generation as the RES share increases (look especially at "none" and "DC" family of scenarios). Resorting

		Available Options			
		None	Only H	Only DC	Both
RES penetration	60%	1.04	1.00	1.47	1.46
	70%	1.07	1.03	1.49	1.49
	80%	1.17	1.06	1.70	1.59
	90%	1.35	1.18	1.94	1.62

TABLE IX
IMPORTS-EXPORTS VARIABILITY IN 2050.

to energy storage is impressively beneficial. Peaks in demand can be met by consuming previously stored energy rather than having invested to additional capacity only for this reason. In addition, let us quote that flexibility-related constraints in the model (such as large power plants limited cycling ability) impel the model solution to contain the installation of flexible units. Operating the latter with a blend of hydrogen and natural gas increases their capacity factor and, hence, reduces the portion of their installed capacity that remains unused.

The effect of transmission enhancement is less pronounced in this case. It stems from the increased ability it introduces for better coordination of power plants installed far from each other.

Closing this results section, it is of interest to show how are inter-country flows affected by the RES and the two enabling technologies deployment in terms of their variability. As a measure of this, we have resorted to computing the standard deviation of each country's imports-exports, over the entire 8760-hour sample in 2050. We have observed that, with only few exceptions, they all follow a similar pattern. Power flow variability increases as RES penetration increases and, more pronouncedly, when interconnecting capacity increases. On the contrary, the presence of hydrogen storage seems to slightly decrease power flow variability. Since it is not practical to show each country's standard deviation value for every scenario, we have constructed an index that, for each scenario, takes a value representative of the aforementioned standard deviation. First, each country's standard deviation value has been normalized by dividing it with this country's standard deviation value of scenario "60-H" (which, in general, turns out to have the lowest such value). Then, the average of the countries' normalized standard deviation values has been computed for each scenario. The result is shown in Table IX.

IV. DISCUSSION - CONCLUSION

Different ways exist for achieving the decarbonization targets that have been set by the EU. Clearly, doing this almost solely by RES (resulting in extremely high penetration of those resources into the energy mix) is worth being studied as it is a strategy that provides advantages related to environmental and security of supply reasons.

The investigations presented in this paper have suggested that, in the aforementioned limit case scenarios, RES penetration becomes very expensive without support of proper moderation to deal with the intermittent nature of the basic renewable sources of energy.

The variability of wind and sun raises two important issues which lead to an increased cost. First, the fact that installing more capacity of those resources results in them being used at a lower capacity factor, and, second, the fact that increased system flexibility and back-up reserve is needed to cover RES variability and undispatchability. The first issue is revealed by the results in Table VII, while the second by those in Table VIII. Focusing on the scenarios with no available moderator, the results show that, as the RES penetration increases, variable renewable investments are used less efficiently while the penetration of practically unused generation capacity is increased. Both issues imply costs, making the MWh produced by variable RES increasingly expensive.

The results show that, at least for the EU system that we have simulated, it is in all cases worth investing in a moderator, up to an extent that depends on the scenario and the moderator (the marginal benefit of investing in and operating the moderator should exceed the marginal cost of producing power from variable RES without the additional moderator). It is not a surprise that higher RES penetration levels justify higher investments in moderation (due to the increasingly higher cost of producing power from variable RES). Simulation results have suggested that enhancing the transmission system is the preferred moderation choice for lower RES penetration, while, as RES penetration levels increase energy storage becomes a more beneficial option. Another remark that the results have suggested is that energy storage is a more suitable way for dealing with the increased back-up demands. This seems to be due to the fact that the power plants that retransform the stored energy into electricity provide directly flexible power capacity, while additional transmission lines are beneficial to this issue only in an indirect way.

The methodology used to model energy storage in the form of hydrogen could be used to model other forms of large scale energy storage as well. It would be of interest, indeed, to check out the results of a similar optimization involving various competing energy storage possibilities. It should be pointed out, however, that quantitative results from analysis like the one presented in this paper should be read with caution since the related technologies have not reached a fully commercialized level, hence cost data used in the models are rather an anticipation of what level of maturity is the related technology expected to reach. Closing, let us quote that an interesting emerging issue worth further investigation is the coupling of different energy carrier networks. In those hybrid systems energy would be suitably converted from one form to another. Energy carrier networks, such as heat or hydrogen, could thus act as storage means or even as load in case of excessive electricity availability.

REFERENCES

[1] EEA, *Europe's onshore and offshore wind energy potential: An assessment of environmental and economic constraints*. European Environment Agency, 2009.

[2] A. Jaeger-Waldau, "Photovoltaics and renewable energies in europe," *Renewable and Sustainable Energy Reviews*, vol. 11, no. 7, pp. 1414 – 1437, 2007.

[3] IEA, *Technology Roadmap Solar photovoltaic energy*. International Energy Agency, 2010.

[4] B. Gupta, "Status and progress in solar thermal research and technology," *Energy*, vol. 12, no. 3-4, pp. 187 – 196, 1987. Status of Solar Thermal Research.

[5] P. Denholm and M. Hand, "Grid flexibility and storage required to achieve very high penetration of variable renewable electricity," *Energy Policy*, vol. 39, no. 3, pp. 1817 – 1830, 2011.

[6] M. J. Grubb, "The integration of renewable electricity sources," *Energy Policy*, vol. 19, no. 7, pp. 670 – 688, 1991.

[7] B. K. Sovacool, "The intermittency of wind, solar, and renewable electricity generators: Technical barrier or rhetorical excuse?," *Utilities Policy*, vol. 17, no. 3-4, pp. 288 – 296, 2009.

[8] EC, *A Roadmap for moving to a competitive low carbon economy in 2050*. http://ec.europa.eu/clima/policies/roadmap/: EUROPEAN COMMISSION, 2010.

[9] EC, *Energy Roadmap 2050*. http://ec.europa.eu/energy/energy2020/roadmap/: EUROPEAN COMMISSION, 2011.

[10] B. Lehner, G. Czisch, and S. Vassolo, *EUROPES HYDROPOWER POTENTIAL TODAY AND IN THE FUTURE*. Institut fuer Solare Energieversorgungstechnik (ISET), Kassel, Germany, 2010.

[11] T. J. Hammons, *Electricity Infrastructures in the Global Marketplace*. InTech, 2011.

[12] S. Hagedoorn, M. Hoogwijk, and T. Winkel, *Potential of Geothermal Energy A literature study on European potential assessments*. Ecofys 2009, 2009.

[13] K. Skytte, P. Meibom, and T. C. Henriksen, "Electricity from biomass in the european union–with or without biomass import," *Biomass and Bioenergy*, vol. 30, no. 5, pp. 385 – 392, 2006.

[14] M. Milligan, "Variable renewable generation impact on operating reserves," *National Renewable Energy Laboratory*, 2011.

[15] R. Green and N. Vasilakos, "The long-term impact of wind power on electricity prices and generating capacity," Discussion Papers 11-09, Department of Economics, University of Birmingham, Mar. 2011.

[16] A. Conejo, "Keynote presentations are current electricity markets suitable to integrate non-dispatchable producers?," in *Energy Market (EEM), 2011 8th International Conference on the European*, pp. xiii –xv, may 2011.

[17] L. Goransson and F. Johnsson, "Dispatch modeling of a regional power generation system - integrating wind power," *Renewable Energy*, vol. 34, no. 4, pp. 1040 – 1049, 2009.

[18] T. Ackermann, G. Ancell, L. Borup, P. Eriksen, B. Ernst, F. Groome, M. Lange, C. Mohrlen, A. Orths, J. O'Sullivan, and M. de la Torre, "Where the wind blows," *IEEE Power and Energy Magazine*, vol. 7, no. 6, pp. 65 – 75, 2009.

[19] D. Corbus, D. Lew, G. J. W. Winters, and F. V. H. J. M. B. Zavadil, "Up with wind," *IEEE Power and Energy Magazine*, vol. 7, no. 6, pp. 36 – 46, 2009.

[20] J. DeCesaro, K. Porter, and M. Milligan, "Wind energy and power system operations: A review of wind integration studies to date," *The Electricity Journal*, vol. 22, no. 10, pp. 34 – 43, 2009.

[21] O. Jaramillo, M. Borja, and J. Huacuz, "Using hydropower to complement wind energy: a hybrid system to provide firm power," *Renewable Energy*, vol. 29, no. 11, pp. 1887 – 1909, 2004.

[22] E. D. Castronuovo and J. A. P. Lopes, "Optimal operation and hydro storage sizing of a windhydro power plant," *Electrical Power and Energy Systems*, vol. 26, no. 10, pp. 771 – 778, 2004.

[23] J. B. Greenblatt, S. Succar, D. C. Denkenberger, R. H. Williams, and R. H. Socolow, "Baseload wind energy: modeling the competition between gas turbines and compressed air energy storage for supplemental generation," *Energy Policy*, vol. 35, no. 3, pp. 1474 – 1492, 2007.

[24] Alfred and Cavallo, "Controllable and affordable utility-scale electricity from intermittent wind resources and compressed air energy storage (caes)," *Energy*, vol. 32, no. 2, pp. 120 – 127, 2007.

[25] M. Korpas and A. Holen, "Operation planning of hydrogen storage connected to wind power operating in a power market," *IEEE Transactions on Energy Conversion*, vol. 21, no. 3, pp. 742 – 749, 2006.

[26] M. Aguado, E. Ayerbe, C. Azcarate, R. Blanco, R. Garde, F. Mallor, and D. M. Rivas, "Economical assessment of a wind-hydrogen energy system using windhygen software," *International Journal of Hydrogen Energy*, vol. 34, no. 7, pp. 2845 – 2854, 2009.

[27] L. Goransson and F. Johnsson, "Large scale integration of wind power: moderating thermal power plant cycling," *Wind Energy*, vol. 14, no. 1, pp. 91 – 105, 2011.

[28] D. J. Swider, "Compressed air energy storage in an electricity system with significant wind power generation," *Energy Conversion, IEEE Transactions on*, vol. 22, pp. 95 –102, march 2007.

[29] A. Tuohy and M. O'Malley, "Pumped storage in systems with very high wind penetration," *Energy Policy*, vol. 39, no. 4, pp. 1965 – 1974, 2011.

[30] E3MLab, "The primes model," *E3MLab*, 2009.

[31] A. Converse, "The impact of large-scale energy storage requirements on the choice between electricity and hydrogen as the major energy carrier in a non-fossil renewables-only scenario," *Energy Policy*, vol. 34, no. 18, pp. 3274 – 3376, 2006.

[32] D. M. Steward, *Analysis of Hydrogen and Competing Technologies for Utility-Scale Energy Storage*. NREL, 2010.

[33] H. Ibrahim, A. Ilinca, and J. Perron, "Energy storage systems–characteristics and comparisons," *Renewable and Sustainable Energy Reviews*, vol. 12, no. 5, pp. 1221 – 1250, 2008.

Prof. P. Capros is Professor of Energy Economics and Operation Research at the Department of Electrical and Computer Engineering of NTUA. He holds an engineering degree from NTUA, 3 DEAs in Economics, Informatics and Operations Research form ENSAE, University of Dauphine, Paris and a Doctorat dEtat in Mathematical Economics from University Pierre et Marie Curie, Paris. He has been the Chairman of the Regulatory Authority for Energy in Greece and member of the Board of Directors of the Greek Public Corporation. He has widely published and conducted research in Energy, Economic and Environmental analysis and modelling.

Nikolaos Tasios has graduated from NTUA, Department of Electrical and Computer Engineering. At present he carries out research within E3M-Lab in the field of stochastic modelling of power systems.

Adamantios Marinakis holds Ph.D. and D.E.A. degrees in Electric Power Systems from the University of Liege, Belgium and an engineering degree from the Department of Electrical and Computer Engineering, NTUA, Greece. His research interests focus on power system operation and optimization, electricity markets and energy economics.